BROWSE BASIN GAS TECHNICAL REPORT
DEVELOPMENT OPTIONS STUDY

REPORT 2 OF 3

DEVELOPMENT CONCEPTS FOR
DEVELOPMENT OF BROWSE BASIN GAS

Prepared for

THE NORTHERN DEVELOPMENT TASKFORCE

May 2008

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IV. Details of Interests in Woodside Operated Project
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INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbons production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin joint ventures, one operated by Woodside Energy Limited (Woodside), and the other by INPEX Browse Ltd (INPEX), are planning to use their known gas resources for “greenfields” land based Liquefied Natural Gas (LNG) projects1 (Figure 1).

The two projects are based on total gas resources of approximately 34 Trillion cubic feet (Tcf)². While some of these resources were discovered over thirty years ago, the basin is “gas prone” and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the “logical” sites for a land based LNG plant to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast (Figure 2). The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations (Broome and Cape Leveque).

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a “stand alone” basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and INPEX has chosen the Maret Islands as its preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 Mtpa.

The Kimberley Northern Development Taskforce (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from DoIR. The taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

The Taskforce, through DoIR, has retained Gaffney, Cline & Associates (GCA) to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled “Browse Basin Development Options Study” (The Study).

1 During the course of the study Shell Development (Australia), (Shell) announced that it plans to develop the Prelude field, in the Browse Basin, using a floating LNG facility (FLNG) with no onshore processing facilities. The proposed development is described briefly in Section 2.4. Since it will not use an onshore processing hub it is not considered in the report.

2 Conversion factors to convert values expressed in conventional oil field units to metric units are shown in Appendix III.
The objective of the Study is to review specific technical and economic issues surrounding the processing of existing and yet to be discovered resources at a common LNG plant location or hub. The study has been undertaken in three parts as follows:-

1. Review the existing site selection processes undertaken by Woodside and INPEX and provide commentary on the technical suitability of the sites considered to date in the context of a gas processing hub.

2. Consider and evaluate the key technical issues governing the offshore facilities required to develop Browse Basin Gas in the context of a gas processing hub.

3. Review the potential for an onshore infrastructure hub to support Browse Basin gas development and comment on the key technical, commercial and economic issues surrounding the co-location of the gas processing infrastructure at an onshore infrastructure hub.

Separate reports have been prepared for each of the three areas of review outlined above. This second report discusses key technical issues associated with development of the fields and identifies issues that may potentially constrain offshore developments to support an onshore hub.

The scope of work for the second report is shown in Appendix I. A glossary is included in Appendix II.
CONCLUSIONS

- The main effect of the location of an onshore gas processing hub on offshore developments is on the length of the pipelines from the fields to the hub. For a single pipeline, this is likely to be in the order of A$4 million/km. In the extreme, the need for a long pipeline to shore could make development uneconomic.

- A lesser effect will likely be the currents and seafloor conditions in the vicinity of the shore which, while not changing the offshore development plans, will impact on the cost of pipelines to shore at the hub location. A detailed survey and bathymetric data will be required to identify pipe laying issues at each of the potential hub locations.

- With the exception of hubs located at Burrup or Darwin, other than the cost of the pipeline, hub location is likely to have little impact on offshore development plans.

- Darwin and Burrup are significantly further from the Browse fields than the other potential hub locations under consideration. If a hub is located at Darwin or Burrup, offshore platforms with compressors will be required along the pipeline routes and condensate will more likely be separated, stored and loaded offshore.

- If a hub were located at Burrup or Darwin, the availability of sufficient quantity of offshore pipeline is likely to be a critical schedule item.

- Where a field or platform is more than about 150 km from onshore facilities condensate will likely be separated from the gas and be either loaded offshore or sent to shore in a separate pipeline. The fields for both proposed developments are more than 150 km from the onshore gas processing hubs considered.

- Because fields in the Browse Basin are expected to contain high levels of carbon dioxide, gas developments will likely include an offshore platform, either fixed or floating, to dry the gas and make it non-corrosive to allow the use of carbon steel pipelines downstream of the platform.

- Whether the platform is placed over the field, to allow the use of dry wellheads and to minimise the length of flow lines, or in shallower water some distance from the field, will depend on water depth, geotechnical conditions at the field and the distance to water depth where a fixed platform can be built.

- Well tubulars, flow lines and subsea manifolds upstream of the platform will likely be made of corrosion resistant alloy which is expensive.

- Although there is potential for different development projects to share offshore facilities this is considered unlikely, particularly in the early stages of the Basin development. The chance of this happening is largely independent of whether a hub or stand-alone onshore facilities is used. It is also largely independent of the location of an onshore gas processing hub.
DISCUSSION

1. **BROWSE BASIN**

1.1 **General**

The Browse Basin is a large (180,000 km$^2$) basin located off the northwest coast of Western Australia. Water depths over the basin range from 20 m to more than 2,000 m. Large gas fields were discovered in the basin in the early 1970s but, in contrast to those in the North West Shelf, have remained undeveloped because of the longer distance to shore and deeper water. However, two Browse Basin joint ventures, one operated by Woodside and the other by Inpex are planning to develop their gas resources for LNG projects.

The eastern margin of the Bowen Basin comprises the Yampi Shelf, which consists of an eastward-thinning sequence of Mesozoic and younger sediments. The southern part of the basin comprises the Leveque Shelf, an offshore extension of the Kimberley Block. The Leveque Shelf separates the Browse Basin proper from the adjacent Fitzroy Graben and Rowley Sub-basin of the Canning Basin, (Figure 3).

The basin has two distinct depocentres, the Caswell and Barcoo Sub-basins. These depocentres contain in excess of 15 km sedimentary section and lie in 100 – 1,500 m water depth. The outer Browse Basin underlies the deep-water Scott Plateau. The carboniferous section is predominately fluvio-deltaic and the Permian-Early Triassic section is marine. Early Cretaceous claystones provide a thick regional seal.

The basin is considered to be gas prone and despite the large fields already discovered has been relatively lightly explored. Reports by the US Geological Survey and Longley$^3$ support the view that the basin contains over 30 Tcf of undiscovered gas.

1.2 **Fields in the Browse Basin**

1.2.1 **Resources**

Approximately 40 Tcf has been discovered in the Browse Basin. Table 1 shows the discovered fields in the Browse Basin listed by DOIR with their estimated gas and condensate resources. (This table does not include all the discovered resource, for example Crux and Prelude).

A total gas resource base discovered and yet to be discovered in the order of 70 Tcf, would indicate that long term LNG capacity for gas from the Browse Basin would be in the range of 20 – 35 Mtpa. Based on recent announcements, some of this capacity might be located offshore.

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TABLE 1
FIELDS IN THE BROWSE BASIN - RESOURCES

<table>
<thead>
<tr>
<th>Field</th>
<th>Permit</th>
<th>Operator</th>
<th>Gas P50 Tcf</th>
<th>Cond P50 MMbbl</th>
</tr>
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<tbody>
<tr>
<td>Torosa</td>
<td>WA-30-R</td>
<td>Woodside</td>
<td>11.4</td>
<td>121</td>
</tr>
<tr>
<td>Brecknock</td>
<td>WA-29/32-R</td>
<td>Woodside</td>
<td>5.3</td>
<td>109</td>
</tr>
<tr>
<td>Calliance</td>
<td>WA-28/31</td>
<td>Woodside</td>
<td>4.0</td>
<td>87</td>
</tr>
<tr>
<td>Ichthys</td>
<td>WA-285-P</td>
<td>Inpex</td>
<td>9.5</td>
<td>315</td>
</tr>
</tbody>
</table>

Notes:
1. The Torosa field was formerly known as Scott Reef
2. The Calliance field was formerly known as Brecknock South
3. Ichthys includes both the Brewster and Plover reservoir units
4. In May 2008 Inpex revised Ichthys reserves upwards to 12.8 Tcf gas and 527 MMbbl condensate.

TABLE 2
FIELDS IN THE BROWSE BASIN
CONDENSATE GAS RATIOS

<table>
<thead>
<tr>
<th>Field</th>
<th>Bbl/MMscf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Torosa</td>
<td>11</td>
</tr>
<tr>
<td>Brecknock</td>
<td>21</td>
</tr>
<tr>
<td>Calliance</td>
<td>22</td>
</tr>
<tr>
<td>Ichthys</td>
<td>33</td>
</tr>
</tbody>
</table>

Notes:
1. Based on the reserves reported by DOIR Ichthys, condensate ratio is 33 bbl/MMscf.
2. Based on the updated reserves reported by Inpex, May 2008, it is 41 bbl/MMscf.

Other fields have been discovered in the Browse Basin, but do not have resource volumes recorded by DOIR. The Crux Field, operated by Nexus Energy in AC/P23, was discovered in 2000. Nexus has since drilled three appraisal wells on the field. Following the drilling of Crux 2ST in 2007, GCA estimated the gas and condensate resource of about 2 Tcf with 66 MMbbl condensate (Best estimate).

The Echuca Shoals field in WA-377-P, also operated by Nexus, was discovered in 1983. The field is located in close proximity to the Ichthys field. In 2007, Shell discovered the Prelude field with an estimated 2-3 Tcf, in WA-371-P next to Ichthys. The Argus field was discovered in 2004. The Argus field was reported to have poor porosity and permeability.
1.2.2 Torosa, Brecknock, Calliance

The Torosa, Brecknock and Calliance gas condensate fields are located approximately 290 km off the Kimberley coast, 400 km NW of Broome, in the Browse Basin, in petroleum retention leases and permits WA-R-2, WA-TR/5, WA-28-R, WA-29-R, WA-30-R, WA-31-R, WA-32-R and WA-275-R. The permits and leases are held by Woodside Petroleum Ltd, BHP Billiton Petroleum Pty Ltd, BP PLC, Chevron Corporation and Royal Dutch Shell PLC. Details of the interests in the different leases and shown in Appendix IV. The fields are estimated to contain approximately 20.7 Tcf gas and 317 MMbbl condensate.

The Torosa field (previously known as Scott Reef) was the first field discovered in 1971. Brecknock was discovered in 1979 and Calliance (formally Brecknock South) in 2000. Part of the Torosa field lies beneath Scott Reef but the rest of it and the other two fields are in water depths of 400 – 700 m. The Torosa and Calliance fields are about 70 km apart. The Brecknock field is between the two.

The condensate content varies from field to field with Calliance having the highest condensate ratio. The average across the three fields is 17 bbl/MMscf. Carbon dioxide content is in the range 4% - 12%. Resource volumes for each of the fields are shown in Table 1.

1.2.3 Ichthys

The Ichthys Field is in exploration permit WA-285-P R1. The permit is held by Inpex Corporation 76% and Total E&P Australia 24%. The field is located approximately 230 km from the mainland and 440 km north of Broome in 260 – 280 m water depth. The field is approximately 40 km long and 20 km wide.

The field was discovered by the Dinichthys-1, Gorgonichthys-1 and Titanichthys-1 wells in 2000 – 2001. The field contains two sandstone reservoir units, the upper early Cretaceous Brewster Member and the lower early-mid Juassic Plover formation.

The field is estimated to contain 12.8 Tcf gas and 527 MMbbl condensate. It contains two reservoir units, the Brewster and the Plover formations. The Brewster gas is condensate rich with a gas condensate ratio of about 53 bbl/MMscf and a carbon dioxide content of 8.5%, while the Plover gas contains about 12 bbl/MMscf condensate and has a carbon dioxide content of 17%. The carbon dioxide is believed to be of volcanic origin.

1.2.4 Crux

The Crux field, located in AC/P23, is approximately 150 km to the northeast of Ichthys. Interests in the field are held by Nexus 85%, and Osaka Gas 15%. The field is made up of four distinct reservoir units, the Montara formation, Plover formation, and Nome formation “A” and “B” sands. At the reservoir level the field forms a Y-shaped structure that trends in a SW-NE orientation and is bounded by faults trending in approximately the same direction.
Four wells have been drilled on the field. Crux-4, the most recent well, was completed only earlier this year. Following the drilling of Crux 2ST in 2007 GCA was asked to estimate the gas and condensate resource. GCA’s Best estimate of the gas resource was about 2 Tcf gas with 66 MMbbl condensate.

In early 2007, Nexus sold the rights to the gas, excluding condensate, to Shell Development (Australia). The gas sales agreement enables Nexus to undertake a gas recycle project to recover condensate until 31 December 2020, at which time Shell will assume ownership of the permit and will have the right to the gas and any remaining condensate.

1.2.5 Prelude

The Prelude field in the northern part of the Browse Basin, was discovered by Shell in 2007. The field is located in WA-371-P in 250 m water depth. The field is estimated to have 2-3 tcf gas. There is very little information regarding the Prelude field in the public domain.
2. FIELD DEVELOPMENTS

2.1 Brecknock, Calliance and Torosa Field Development

Current development plans by the Operator, Woodside, are at a very preliminary stage and a number of possible development options are still under consideration. These all revolve around production of about 15 Mtpa LNG using two or three LNG trains.

Notional upstream development plans are described in the Browse Upstream Development prepared for the EPBC Act Referral of Proposed Action, February 2008\(^4\) (Figure 4).

The base case notional development plan is to develop jointly the three fields using a combination of subsea wellheads (that is with wellheads on the sea floor) and dry wellheads based on floating platforms such as tension leg platforms (TLPs). Subsurface well centres would be located on North Torosa, South Torosa, Brecknock and Calliance development area and a floating platform, with dry trees, installed at each of the well centres at North Torosa and at Calliance. Pipelines would take production from each of the subsurface well centres to a floating platform where bulk water would be removed, treated and disposed of.

The fluids (gas and condensate) would then flow by pipeline to a processing platform located in shallower water, 80 – 120 m water depth. The platform, which could be either a steel jacket or a concrete gravity structure (CGS), would be located about 110 km from Torosa and about 60 km from Brecknock and Calliance. On the platform condensate would be separated and stabilized\(^5\) for loading offshore, gas would be dried and sent by pipeline to shore for processing. If the platform was a concrete gravity structure stabilized condensate would be stored in the base of the platform before being loaded onto tankers though a loading buoy for transport to markets. If the platform was a steel jacket, a floating storage and offloading (FSO) vessel would be employed to store condensate before being loaded onto tankers. Compression would likely be installed on the platform later in the life of the project when reservoir pressure declined. The Browse joint venture is still actively considering a number of different offshore development options and onshore sites as potential locations for onshore processing facilities.

It is proposed, subject to feasibility studies and the relevant commercial/regulatory framework, that carbon dioxide removed from the produced gas will be geosequestrated offshore, possibly back into one of the fields to be produced.

2.2 Ichthys Field Development

Current plans by the Operator are to develop the Ichthys Field to produce 8.4 Mtpa LNG with associated condensate and LPG. The field will be developed, using subsea wells and manifolds, producing to a floating central processing facility (CPF) in the form of a semi submersible platform (Figure 5). At the CPF, liquids will be separated from the gas and condensate and water separated. The gas and condensate will be dried and then transported to the onshore processing facilities in separate pipelines. Produced water will be cleaned and discharged overboard. Provision will be made for installation of compression facilities at a later time.

\(^4\) Available at Woodside.com.au
\(^5\) Condensate is stabilised to reduce its vapour pressure to allow it to be stored at and transported in tankers. The condensate is heated and the pressure reduced to allow gas dissolved in the condensate to be removed.
Gas will be produced at a constant rate of about 1.4 Bcf/d until production starts to decline after 20 to 30 years. Condensate production will commence at over 70,000 bbl/d and will decline over time as the reservoir pressure decreases. LPG production will remain at 40,000 – 50,000 bbl/d while the Brewster reservoir is being produced and will then decline as increased amounts of gas are drawn from the Plover reservoir.

Inpex plan to initially develop the Brewster reservoir unit, since it has a significantly higher condensate content. As the pressure in the reservoir falls over time, it is anticipated that compression will be installed, followed by development of the Plover reservoir unit. It is anticipated that a total of 35 – 40 wells will be required over the life of the field.

Inpex has conducted an extensive site selection survey and determined that the Maret Islands are the most suitable location for the gas liquefaction facilities. The gas and condensate pipelines from the CPF to the Maret Islands will be approximately 190 km. The following processing facilities are proposed for Maret Island:

- Further gas drying
- Carbon dioxide removal
- LPG extraction, propane and butane separation and storage
- Condensate stabilization and storage
- Gas liquefaction and storage

It is proposed to dispose of carbon dioxide through biosequestration, that is planting trees.

It is envisaged that two ship berths will be provided, one dedicated to LNG loading and the other for shared LNG, propane, butane and condensate loading.

2.3 **Crux Field Development**

Nexus Energy, operator of the Crux Field, plan a gas recycle project on the Crux Field to recover condensate. Four wells have been drilled on the field, environmental approval has been received and a preliminary development plan submitted to the regulator. FID is expected in 3Q 2008.

The project will consist of gas production from subsea wells, to a floating production storage and offloading vessel (FPSO) where gas will be processed to recover condensate. The gas will then be recompressed and injected back into the reservoir. Stabilised condensate will be stored on the FPSO and transferred from the FPSO to tankers for transport to market. A gas recycle rate of 900 MMscf/d is planned, which will produce a peak condensate rate of 32,700 bbl/d.

The rights to the hydrocarbon remaining in the field at the end of 2020, after the gas recycle project, pass to Shell Development (Australia) which will have the right to extract the gas and any remaining condensate.
2.4 Prelude Field Development

In April 2008, Shell announced that it proposed to develop the Prelude Field, in the northern section of the Browse Basin, using a floating LNG facility. The field is in approximately 250 m water depth. Prelude, in W-371-P, was discovered by Shell in 2007. The FLNG facility will be designed to produce 3.5 Mtpa LNG plus LPG and condensate. All the gas processing and product storage will be on the facility and the products will be loaded directly from the FLNG facility into tankers. There will be no pipelines to shore.

The facility will be moored to the seabed via a turret, around which the facility can weather vane. The steel substructure will be approximately 480 m long and 70 – 80 m wide. Gas will be produced from the reservoir using either subsea wells, connected to subsea manifolds or wells with dry wellheads located on a wellhead platform. Reservoir fluid will flow from the wells to the FLNG facility, via flowlines and flexible risers used to accommodate the motions of the FLNG facility. All gas processing that is normally done on shore will be done on the FLNG facility.
3. FACTORS EFFECTING OFFSHORE GAS DEVELOPMENTS

3.1 Introduction

There are a number of factors that affect the choice of components that make up an offshore development. These interact with each other and to understand how the choice of an onshore hub location might effect an offshore development it is necessary to understand the impact of these factors. The factors considered are:

- Water depth
- Carbon dioxide content
- Condensate content
- Reservoir drive mechanism
- Distance to land
- Hydrate formation

These factors are outside the control of the developer and present challenges of different degrees of magnitude that must be resolved to arrive at a successful development.

In most cases, there are a number of alternative developments that can successfully develop a field and the challenge is to find the option with the lowest capital and operating cost that meets the necessary operating, safety and environmental criteria.

The ways in which the location of an onshore hub might effect offshore development are discussed in Section 4.

3.2 Water Depth

One of the main decisions to be made when planning an offshore development is whether the wells will be completed above sea level or on the sea floor. Wells completed above sea level are less costly to drill, work over and for wire line operations. However, in order to complete a well above sea level, it is necessary to have a platform above sea level and support structure for the wells. The platform can be fixed to the sea floor, or a floating platform held in place with tethers to the seafloor. Wells completed at the sea floor do not need a large support structure but are more expensive to drill and work over. They also need some form of remote control system to control the flow of fluid from the well.

Water depth is the main determinant as to whether field development wells have dry trees, or wet trees on the sea floor. In shallow water almost invariably, a simple fixed platform is built to allow wells to be completed with dry trees. In many cases, for a field in shallow water where a platform is built, process equipment is installed on the platform. In other cases, the platform might contain only wellheads and all the fluid produced from the wells is transported either to shore or to another platform for processing. In some cases, where a large number of wells are required for a field that covers a large areal extent, more than one platform will be built. Frequently, it is the need to process gas or oil close to the field, combined with a desire for dry trees that supports a decision to install some form of platform.

As water depth increases, the cost of a platform to support dry trees increases and a point is reached where it is more economic to use subsea completions. Conventional steel jacket platforms have been installed in water depths up to about 400 m. For example, the Bullwinkle platform completed by Shell in the Gulf of Mexico in 1991 in 412 m water depth, the
Harmony platform installed in 1992 by ExxonMobil in 366 m water depth in the Santa Barbara Channel and the Pompano platform installed by BP in 393 m water depth, also in the Gulf of Mexico.

A CGS is an alternative to a steel jacket platform. The Troll A CGS was installed by Shell in the Norwegian North Sea in 303 m water in 1996. CGSs have the advantage that the base can be used for storage, for example for condensate or oil if offshore loading of liquids is to be used.

In more recent years, technology has advanced with respect to subsea completions and alternatives to steel jacket platforms, making it unlikely that steel jacket platforms or CGSs will in future be used in water depths greater than 300 m. For water depths between 150 m and 300 m operators have a choice between steel jacket platforms, CGSs and the alternatives discussed below. See Figure 6.

A number of different platform options have been used for fields in deeper water. For production of oil from fields in deep water by far the most common type of development is the use of subsea wells producing to an FPSO, where the FPSO is usually ship shaped, and in many cases is a converted crude tanker. Gas and water are separated from the crude on the FPSO, the crude is stabilized to make it suitable for transport, water is cleaned and discharged overboard and the gas is either flared or reinjected back into the reservoir. This is appropriate for crude production where the use of an FPSO obviates the need for a pipeline to shore but is not suitable for gas production. It is not possible to store large volumes of gas offshore and gas is not transported by ship, unless it is first liquefied, so a pipeline is required to carry gas to shore either for liquefaction, conversion to a shippable product such as methanol, or for domestic distribution.

Compliant towers have been used in water depths of 300 m to about 900 m. A compliant tower is a narrow flexible tower with a piled foundation that supports a conventional deck for drilling and operations. Compliant towers have been used in the Gulf of Mexico.

Another option for water depths greater than about 300 m is a tension leg platform. Tension leg platforms have been installed in water depths up to 1,200 m. They consist of a floating structure held in place by vertical, tensioned tendons connected to the seafloor by pile secured templates. They have limited vertical motion and allow the use of dry wellheads and provide a platform for process equipment.

A third option is a floating production system (FPS) which consists of a semi-submersible that has drilling and production equipment. It is anchored to the sea floor with a number of mooring chains to keep it on location. The wellheads are located on the seafloor and produce to the FPS through flexible risers designed to accommodate the motion of the FPS. FPSs can be used in water depths up to about 2,300 m.

Another option is a spar platform. A spar platform consists of a large-diameter single vertical cylinder supporting a deck. The hull is moored with a taut catenary system of lines anchored to the sea floor.
Offshore Production Systems

Project: KK1177 May '08 Checked: Fig. 6
Tension leg platforms (TLPs), compliant towers, and spars have all been used in deep water and allow wells to be completed with dry wellheads. FPSOs, mini TLPs and FPSs allow process facilities to be installed in deep water, but do not cater for dry wellheads. In these cases, subsea wells are used with flexible flowlines led to the FPSO, mini TLP or FPS. The deepest installation of a form of platform to date is Na Kika semisubmersible FPS, in the Gulf of Mexico in over 1,900 m water depth.

Subsea completions are used when only a limited number of wells are required and the wells can be tied back to a nearby platform, where the water is deep and the use of subsea wells is less expensive than a structure supporting dry wellheads or where the water depth is such that installation of a structure to support dry wellheads is not feasible. Subsea completions have been installed in water depths over 2,000 m, for example Coulumb in 2,300 m water depth in the Gulf of Mexico.

History has shown that the type of offshore production systems used in deep water depends on the geographic area it is to be installed in, and the operator, as much as it does on the function it is to perform or the nature of the field and process conditions.

Water depth over the Browse basin ranges from about 20 m to over 2,000 m so it can be expected that any of the above mentioned options could be used for development of fields in the basin.

The Brecknock, Calliance and Torosa fields are in water depths of 400 – 700 m, apart from a section of the Torosa field which is directly below Scott Reef. This means that, from a technical point of view, all or part of the Torosa field could be developed using dry well heads and facilities located on Scott Reef. For Brecknock and Calliance, the water depth is too great for steel jacket platforms or CGSs, so if the use of dry well heads was planned, the choice of a structure to support the well heads would be a compliant tower or TLP. The other alternative is to use subsea well heads. The referral under the EPBC Act submitted by Woodside describes subsea wellheads and TLPS for the development of the Woodside operated project. See Section 2.1.

### 3.3 Carbon Dioxide Content

Carbon dioxide and water form carbonic acid which is corrosive. All the fields in the Browse Basin that are currently under consideration for development contain sufficient carbon dioxide, where steps have to be taken to control corrosion.

There are four methods of preventing corrosion caused by carbon dioxide:

- Use of corrosion resistant alloy
- Drying the gas
- Use of corrosion inhibitor
- Removal of carbon dioxide
3.3.1 Use of Corrosion Resistant Alloy

Corrosion resistant alloy is intrinsically capable or resisting corrosion by wet acid gas. Where gas is corrosive due to the presence of carbon dioxide, it is usual to have production tubing in the wells made of corrosion resistance alloy (CRA). This is especially so where subsea well heads are used, since workovers are expensive.

CRA materials can also be used for flow lines and trunk lines. Since the cost of CRA is generally of the order of 5 times the cost of carbon steel pipeline material it is usual to use the CRA material as a cladding in the pipelines rather than use pipelines made of solid CRA. Generally the industry tends to use CRA pipelines for shorter lengths and smaller diameters. The use of long CRA clad pipelines becomes prohibitively expensive, especially for large diameter lines.

3.3.2 Gas Drying

If gas containing carbon dioxide is dried, the dry gas becomes non-corrosive. The conventional way of drying gas is to separate liquid hydrocarbons from the gas and contact the gas with triethylene glycol (TEG). The liquid hydrocarbons (condensate) are dried using gravity separation of water or a density based process, such as hydrocyclones. The resultant water stream is cleaned and discharged overboard. In order to dry gas to make it non-corrosive, it is necessary to have some sort of platform, fixed or floating, to support the process equipment. Because the drying process involves rotating equipment and a heat source, a platform where gas is dried has historically been manned and is a substantial structure.

3.3.3 Corrosion Inhibitors

Corrosion inhibitors have been developed that reduce the rate of corrosion caused by carbon dioxide. The effectiveness of the corrosion inhibitors depends on the temperature of the gas, the gas composition and other factors such as the gas and liquid velocities in the line. The effectiveness of corrosion inhibitors rely on continuous injection of the inhibitor and good distribution of the inhibitor in the line. They are sometimes used in conjunction with additional wall thickness in the pipeline to allow for a limited amount of corrosion.

3.3.4 Removal of Carbon Dioxide

Carbon dioxide is removed using a process similar to that used to dry gas except that the gas is contacted with an amine solution instead of triethylene glycol. In an offshore environment, it is almost invariably less expensive to dry gas rather than remove carbon dioxide.

3.3.5 Relevance of Carbon Dioxide to proposed Developments

All the fields in the current proposed developments have sufficiently high levels of carbon dioxide, where development plans have to be made to accommodate it. It is an important factor driving the development plans. The EPBC referral prepared by Woodside, on behalf of the Browse Joint Venture states that gas will be processed on an offshore platform, such that it can be transported via a transmission line to an onshore LNG facility. It is presumed that such processing will include gas drying. Inpex plans to dry Ichthys gas on the CPF prior to transmission to Maret Island.
Part of the plans to accommodate carbon dioxide, include plans for disposal of carbon dioxide removed from the gas. Inpex proposes to dispose of carbon dioxide through biosequestration, that is planting trees. It is unlikely that hub location will influence this plan.

The Woodside operated project propose, subject to feasibility studies and the relevant commercial and regulatory framework, to geosequester carbon dioxide removed from the produced gas offshore, possibly back into one of the fields to be produced. If this were to be the case, the main impact of a hub location on carbon dioxide disposal would be on the length of the pipeline used to carry carbon dioxide to the offshore field. Plans by the Woodside operated project for carbon dioxide disposal appear, at this stage, to be in the early stages of development.

3.4 Condensate Content

A high condensate content of a gas adds considerable value to the gas. The condensate is recovered from the gas, stabilised, and sold as a separate product. The Crux gas recycle project relies entirely on the value of the recovered condensate for its economic justification.

However, a development of gas containing condensate needs to take account of the condensate in its design. Whenever two phases (gas and condensate) or three phases (gas condensate and water) flow through long pipelines a liquid phase builds up in the pipeline and exits in the form of slugs. This leads to unstable operation of the pipeline, the gas and liquid flow rate from the pipeline is not steady which can make operation of the liquefaction facilities difficult and necessitates a large volume of high pressure storage (slug catchers) to allow the liquid slugs to accumulate and be processed through stabilisation facilities at a steady rate.

The problems associated with two phase or three phase flow in pipelines depend on the length of the pipeline, the changes in elevation of the pipeline, the condensate content of the gas, pigging frequency and the changes of gas throughput rate. Major slugging is associated with increases in gas rate when large volumes of liquid are swept from the pipeline. Slugging occurs when a subsea pipeline carries two or three phases to a platform or to an onshore processing plant.

The Ichthys field has a higher condensate content than Torosa, Brecknock or Calliance, about 53 bbl/MMscf versus an average of about 17 bbl/MMscf for Torosa, Brecknock and Calliance. These levels are high enough where condensate build up in two phase or three phase pipelines has to be considered.

3.5 Reservoir Drive Mechanism

The energy to produce gas from a reservoir can either come from the expansion of the gas in the reservoir, or the presence of an aquifer pressurising the gas in the reservoir.

In the case where the energy is provided by the expansion of gas in a reservoir, the reservoir pressure decreases, as gas is produced which in turn leads to a reduction of the wellhead pressure. This means that at some point in the depletion of the field, it is necessary to install compression to increase the pressure of the gas into the processing facilities. Where the pipeline from the field to the onshore processing facilities is relatively short, compression is usually installed at the plant inlet. However, where the pipeline from the field is long, it is usually
more efficient to install compression as close as possible to the field. In some cases, this necessitates installing a platform to support the compression facilities.

There are several points regarding offshore compression that should be noted:

- Despite development work being done on the installation of subsea compression, it is still in the experimental stage;
- It is not possible to compress liquid, so liquid must be separated from gas before gas is compressed. The liquid may then be recombined with the gas in a single pipeline or transported in a separate liquids line;
- Offshore compression facilities are almost invariably manned.

Where the field has a strong aquifer drive, it may not be necessary to install compression, however in this case, wells will start to produce water near the end of the life of the field and wet wells will need to be shut in and facilities will need to be designed to handle increased volumes of water.

Information regarding the reservoir drive mechanism for the fields in the proposed developments has not been provided to GCA. However, it is expected that compression will be installed for both developments during the project lives.

### 3.6 Distance To Land

#### 3.6.1 Introduction

Historically, gas processing facilities have been land based. In most cases, this is because gas is distributed and sold through an onshore distribution system to an onshore market, as for example gas from offshore Bass Strait fields goes by pipeline to onshore gas processing plants for distribution and sales in eastern Australia and Tasmania. Also where gas has been converted to a liquid product such as methanol or LNG, for transport to an overseas market, the conversion or liquefaction has been carried out in a land based plant.

However, as gas fields are developed that are further offshore and pipelines to shore get longer pipeline costs increase, so there is an incentive to convert the gas to liquid product such as methanol or LNG in offshore facilities and ship the product directly to markets from offshore facilities.

#### 3.6.2 Offshore Processing

Compared to gas, oil requires little processing before it can be shipped and it is now common practice to develop offshore oil fields, distant from shore, using FPSOs where all the processing is carried out on the FPSOs. There have been several proposals to build floating LNG plants or methanol plants, which obviates the need for pipelines to shore. To date, however these have not eventuated, but for cases where the gas is to be converted to a liquid product, where pipelines to shore based facilities become longer, the incentive to do all the gas processing offshore will increase.
Shell plans to develop the Prelude field in the Browse Basin, using a FLNG facility. See Section 2.4. Shell is also reported to have proposed the use of a floating LNG plant to develop the Sunrise field in the Timor Sea. BHP Petroleum built a small methanol plant in Victoria in the 1990s to test technology for installing a floating methanol plant to process solution gas from offshore oil fields or small offshore gas fields.

3.6.3 Increased Pipeline Length and Diameter

A second impact of increased distance to land is increased pressure drop in pipelines to shore. This may be counteracted by increasing the pipeline diameter or installing compression offshore; both of which are expensive for long pipelines.

Where a pipeline carries a liquid phase increased, pipeline length increases the amount of liquid held in the pipeline and increases the size of liquid slugs that exit the pipeline.

Where a field is developed using subsea completions with no offshore fixed or floating platform, as well as the trunk line carrying wellhead fluid from the field, there will be a number of small pipelines going to the wellheads and manifolds. These smaller lines going to the wellheads will carry fluids such as hydrate inhibitor, corrosion inhibitor, hydraulic fluid for operating subsea valves and exhaust for returning used hydraulic fluid. There will also be an umbilical carrying electric control cables. The length and cost of these smaller lines also increases as fields are developed further from shore.

3.6.4 Compression

Where an offshore gas pipeline is longer than 250 – 350 km, then it is likely to be less expensive to install compression on a platform at a mid point, rather than increase the pipeline diameter. This will depend on water depth and pipeline diameter.

3.6.5 Impact of Hub location

The prime impact of the hub location on the offshore development will be through the increase or decrease it makes to the distance from the fields to the processing hub.

3.7 Hydrates

At high pressures and low temperatures methane forms a solid structure with water, a little like dirty slushy ice, called hydrates. When hydrates form in a pipeline they block the line and have to be removed.

When conditions are suitable for hydrate formation, steps are taken to prevent its formation. Three methods are commonly used to prevent hydrate formation in gas pipelines:

- Remove water from the pipeline
- Injection of methanol
- Injection of glycol

Removal of water requires surface facilities. See Section 3.3.2 for a discussion of water removal and gas drying.
Injection of glycol or methanol into a pipeline is effective in preventing hydrate formation. In recent years, monoethylene glycol (MEG) has become the most commonly used hydrate inhibitor. Wherever the aqueous phase is removed, it is processed to recover the MEG, which is then recycled to be used again. There is a small amount of MEG which is not recovered, the cost of which contributes to operating costs.

For wells in deep water with low water temperatures at the well head provision is usually made to inject MEG at the wellhead. This then requires a pipeline from the MEG recovery facility to the wellheads.

Both proposed developments will have to make provision to prevent hydrate formation.
4. EFFECT OF DISTANCE TO ONSHORE HUB ON OFFSHORE FACILITIES

4.1 Introduction

The onshore processing hub will be located at the coast and for all hub locations in the Kimberly represents the first opportunity to locate processing facilities on land. Land based facilities are considerably less expensive than offshore facilities.

As a hub is located further from a field, the cost of the offshore facilities increases and the type of development that is the least cost changes as the distance increases.

For a gas processing hub located at Darwin or on the Burrup Peninsula, rather than lay a pipeline direct to the hub, it might be less expensive to lay a pipeline from the field to a point on the coast, closer to the field, and then lay an onshore pipeline to the hub. However, unless gas is processed at the point where the line goes ashore, the fact that part of the pipeline is onshore is likely to make little difference to the offshore development plan.

The effect of the distance to the processing hub depends primarily on the water depth at the gas field and the corrosivity of the gas.

4.2 Fields in Shallow Water

Large gas fields in water depths up to 150 – 250 m are likely to have a fixed platform, either a steel jacket or CGS, on the field to allow dry wellheads to be used. The choice between the use of a steel jacket or a CGS depends on geotechnical conditions at the field and cost. The cost of a CGS is highly dependent on a suitable construction site being available. A CGS has the additional benefit of offering storage for liquids in the base of the structure.

In the Browse Basin, it is considered most likely that gas will contain carbon dioxide in which case, the gas and condensate will likely be dried on the platform, so that the gas becomes non-corrosive and allows the use of carbon steel pipelines to shore. This also obviates the need to inject hydrate inhibitor downstream of the platform.

For fields where the gas is not corrosive, carbon steel pipelines can be used and the full well fluid sent directly to shore with all processing done onshore.

Compression would not usually be needed initially, but would be added on the platform later in the field life as reservoir pressure declines.

In the Browse Basin for fields close to the gas processing hub, there would likely be a single large diameter pipeline to shore. After being dried on the platform the gas and condensate would be recombined and sent to shore in a single pipeline as a two phase mixture. As the distance of the field to the onshore hub increases the length of the pipeline to shore increases and because the pressure drop in the pipeline increases as the length increases the diameter of the pipeline would also increase to offset the increased pressure drop.

The increased size of the pipeline, both length and diameter, causes increased liquid hold up in the pipeline which leads to increased slug size. Ultimately as the distance increases it becomes less costly to separate the condensate from the gas on the platform and either lay a separate condensate line to the shore or load the condensate onto tankers offshore. This overcomes slugging and increases the capacity of the gas pipeline. Ultimately when the field is a very long way from shore one of more intermediate compression stations would be installed.
on platforms to boost gas pressure and allow the pipeline diameter to be reduced. If compressors are used offshore condensate has to be separated from the gas before it is compressed.

**Figure 7** shows the length and diameter of existing and planned major gas condensate pipelines. **Figure 8** shows the distance and condensate gas ratio. The figures show that there a number of lines up to about 150 km length, some with quite large diameters and some with high condensate gas ratios. However there are a limited number of gas lines longer than 150 km. There does not appear to be any relationship between the length and condensate gas ratio or diameter, for example, it does not appear that the longer pipelines are lower diameter or lower condensate gas ratio as might be expected.

In summary, for fields in the Browse Basin in water depth up 150 - 250 m, it is likely a platform will be built at or near the field to allow dry wellheads and the gas to be dried and the effect of increasing distance to the hub will be to:

- Increase the length of the gas pipeline to shore.
- Increase the diameter of the gas pipeline to shore.
- Change the optimum development from one where the condensate and gas are sent to shore in a single pipeline to one where the gas and condensate are separated on the platform and either sent to shore in separate pipelines, each carrying only a single phase, or the gas is sent to shore while the condensate is stored and loaded into tankers offshore.

The fields in the two proposed development projects are in water depths over 250 m (except for a portion of Torosa which is below Scott Reef). Both developments propose to separate condensate on an offshore platform. The Woodside operated project proposes to store and load condensate offshore while the Inpex operated project plans to transport the condensate to shore in a dedicated pipeline. See Sections 2.1 and 2.2.
Offshore Multiphase Gas Pipelines - Length and Diameter

Project: KK1177 May '08 Checked: Fig. 7
Major Offshore Gas Pipelines – Length and Condensate/Gas Ratio

Project: KK1177 May '08 Checked: Fig. 8
4.3 **Fields in Deep Water**

The reasons to install platforms for fields in deep water are the same as those for fields in shallow water, that is the benefit of having dry wellheads and the need to remove carbon dioxide to make the gas non corrosive. However, the main difference is that any type of platform in deep water is much more expensive than those in shallow water, for the same deck load. This introduces the option for fields in deep water of installing subsea wellheads in the deep water and laying flow lines from the wells to a platform in shallower water.

If a field is sufficiently close to shore, it is possible to use subsea well completions, gather the gas with subsea manifolds and send the full well stream to shore in a single pipeline. The Snohvit field, in the North Sea, in 340 m water depth, containing up to 8% carbon dioxide, was developed this way. The pipeline, carrying the full production fluid is 143 km long. Because there are no surface facilities near the field control of the subsea facilities, glycol injection for hydrate inhibition, and injection of corrosion inhibitor were also issues that had to be addressed. In many cases fields in deep water are a long way from shore and this is not possible. A pipeline length of about 150 km is probably an upper limit for this type of development. For fields with pipelines longer than this it will likely be necessary to have some form of fixed or floating platform to support processing and control facilities.

Where it is necessary or less expensive to have some sort of offshore platform the location of the platform and the type of platform are considered together. If a platform is located over the field it minimizes the length of the flow lines or risers to the platform. In the Browse Basin this is important because the gas is expected to contain carbon dioxide which will cause it to be corrosive. This means that flow lines containing hot fluid flowing from the wells will likely need to be made of corrosion resistant alloy which is expensive. Minimising the length of the flow lines or risers reduces the cost. Offsetting this however is the fact that the water depth usually decreases towards the shore so if a structure is placed over the field it is in deeper water (and therefore more expensive) than if it is placed away from the field towards the shore. Depending on the type of platform chosen, if the platform is placed over the field it can also be used as a drilling platform and can enable the use of dry wellheads.

The length of the main pipeline to shore does not impact on the choice or location of offshore platform chosen to support gas drying facilities and/or dry wellheads.

In summary for fields in the Browse Basin in water depths over 250 m if the distance to shore is greater than about 150 km, it is likely a platform will be built at or near the field to allow the gas to be dried and possibly to allow the use of dry wellheads. Once a platform of some type is installed, as part of a development of a gas field in deep water, the same issues regarding two phase flow in a long pipeline to shore arise. Therefore the effect of increasing distance to a hub is the same as that for fields in shallow water, namely

- Increases the length of the gas pipeline to shore.
- Increase the diameter of the pipeline to shore.
- Change the optimum development from one where the condensate and gas are sent to shore in a single pipeline to one where the gas and condensate are separated on the platform and either sent to shore in separate pipelines, each carrying only a single phase, or the gas is sent to shore while the condensate is stored and loaded into tankers offshore.
Both the proposed developments are in water depths over 250 m and are more than 150 km from shore. Both the Inpex operated venture and the Woodside operated venture propose to build offshore processing platforms of some type. The Inpex operated joint venture proposes to use a floating CPF in the form of a semisubmersible platform in the vicinity of the Ichthys field while the Browse joint venture could use a conventional steel jacket or CGS located some distance from the field in 80 – 120 m water depth.

Given that all the hub locations under consideration are more than 150 km from the fields and both projects plan to use a platform of some kind, the main effect of the distance from the fields to the onshore processing hub for the proposed projects is the length of the pipeline to the hub. If the hub were to be at Darwin or Burrup, compression platforms would also be needed because of the pipeline length.

The estimated relative lengths and costs of the pipelines to the different hub locations addressed by the study (described in the 1st report), along with the different infrastructure costs are shown in Appendix VI.

If the distance to shore is less than about 150 km, the option exists to flow the full well stream directly to shore in a single pipeline.

4.4 Gas with High Carbon Dioxide Content

To date, the major gas fields discovered in the Browse Basin have a high carbon dioxide content, greater than 4%. The carbon dioxide content in the major fields discovered in the Browse Basin is shown in the following table:

<table>
<thead>
<tr>
<th>FIELD</th>
<th>CARBON DIOXIDE CONTENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Torosa, Brecknock, Calliance</td>
<td>4 – 12%</td>
</tr>
<tr>
<td>Ichthys Brewster</td>
<td>8.5%</td>
</tr>
<tr>
<td>Plover</td>
<td>17%</td>
</tr>
<tr>
<td>Crux</td>
<td>10.5%</td>
</tr>
</tbody>
</table>

Gas with high carbon dioxide content, greater than about 3 – 4 % is corrosive, when water is present. When in contact with carbon steel, the rate of corrosion is significantly increased at high temperature. Since the well fluids in the reservoir are hot, this means that if carbon steel is used high corrosion rates are experienced in the production tubing in the well and in the well flow lines until the gas has cooled to sea temperature or until water is removed from the gas. For this reason CRA is used for these applications.

Because the cost of CRA flowlines is 5 times the cost of carbon steel flow lines there is a cost incentive to either cool the fluid as quickly as possible or to remove the water. Since removing the water is more beneficial than cooling the fluid, in most cases the gas is dried as soon as possible. This can only be done using facilities on some form of platform. Technology is being developed to separate liquid from gas in subsea separators but to dry the gas surface facilities are required.
In some cases the platform is placed over the field so that the length of CRA flow lines is minimized. In other cases, for example in deep water, it is more cost effective to place the platform in shallower water and to use CRA flow lines to the platform.

The distance of the platform from the field depends on a cost trade off between increased cost of CRA flow lines versus decreased cost of the platform as it is placed further from the field in shallower water.

If the platform is placed some distance from the field it is usually more cost effective to collect the flow lines in one or more manifolds and lay one or two pipelines to the platform.

If the platform is located away from the field liquid slugs will form in the pipeline(s) carrying the well fluid to the platform. Liquid can be separated from gas on the platform in large separators or recently subsea separators have been developed to separate gas from liquid in vessels at the base of the platform. To prevent large liquid slugs arriving at the platform the gas rate in the pipeline(s) to the platform should be kept as steady as possible.

As a platform is placed further from a field, to be located in shallower water, the size of liquid slugs arriving at the platform increases so increased high pressure storage is needed to store the liquid slugs. This increases the cost of moving further from the field.

If the separated condensate is to be stored and loaded offshore then it will have to be stabilized offshore to make it suitable for transport. The stabilization facilities will be sized for a certain throughput rate and so high pressure condensate storage will be required to ensure the throughput rate does not exceed the design capacity.

If separated condensate is to be transported to shore for stabilization, storage and loading minimal condensate storage is required on the offshore platform. The condensate can be transported to shore in a single liquid phase condensate line or it can be mixed with the gas and the gas and condensate can be transported in a large two phase pipeline.

For fields with a high carbon dioxide content the distance of a gas processing hub from the field has minimal impact on the location of an offshore platform with respect to the field.

4.5 Gas with Low Carbon Dioxide Content

If the produced fluid has a low carbon dioxide content, then acid gas corrosion is not an issue and all tubulars and flow lines can be made of carbon steel and there is not the same need to dry the gas to allow the use of carbon steel.
In this case an offshore platform might be installed to:

- Dry the gas to prevent hydrate formation;
- Remove condensate from gas to allow a single phase gas pipeline to shore.
- Install compression to allow lower diameter pipeline to shore; or
- Install compression late in field life to allow the reservoir pressure to drawn down to increase gas recovery.

These issues are all issues that have to be addressed for all fields to find cost efficient solutions.
5. OFFSHORE CONDENSATE STORAGE AND LOADING

5.1 Storage Size

Because fields discovered to date in the Browse Basin have a high CO₂ content, offshore platforms will be installed to dry the gas to make it non-corrosive. In order to dry the gas, it is necessary to first separate all liquid condensate and water from the gas. Once the condensate has been separated there are three options for the condensate:

- Mix it with the dry gas and transport it to shore with the gas in a two phase pipeline
- Pipe it to shore in a single phase condensate pipeline
- Stabilize it offshore and store it and load it offshore

The pros and cons and the limitations of sending the condensate to shore in a two phase pipeline are discussed in Section 3.4.

The choice between sending the condensate to shore in a single phase condensate pipeline versus offshore stabilization, storage and loading is based primarily on cost.

Condensate can be pumped long distances through a pipeline carrying only condensate. If the condensate contains wax which precipitates at the operating temperature of the pipeline then a chemical will need to be added to prevent wax deposition. A scraper pig may also be run through the line at regular intervals to remove wax deposited on the pipe wall. Both of these options add to operating costs but are well established technology.

If the condensate is to be stabilized, stored and loaded offshore the main decision to be made is the form of storage to be used. Condensate in Australia is usually transported in Aframax tankers that carry about 100k tonnes. Storage may be sized so that there is sufficient storage for one full load plus a certain number of days to allow for ship slippage or inability to load. The extra number of days used to size the required storage depends on ship reliability, weather conditions at the loading point and the onstream time required for the gas production. For LNG production a very high onstream time is required so 6 – 10 days extra production would be allowed for in sizing the storage. This means that the size of the storage depends to some degree on the condensate production rate.

It is common with gas condensate reservoirs for the condensate production rate to decrease over time, even when the gas production rate is held constant. This is due to the pressure in the reservoir decreasing and condensate becoming liquid in the reservoir and not flowing with the gas to the wells. In such situations storage sized for the initial condensate rate will have surplus capacity later in the field life.

It should be noted that the size of the storage does not relate to the distance from a hub to the field or to the condensate loading point.
5.2 Storage Type

5.2.1. Floating Storage and Offloading

Offshore stabilized liquid storage is most frequently provided by use of a Floating Storage and Offloading (FSO) system. For offshore oil production crude processing facilities are placed on the vessel so the vessel is a floating production storage and offloading vessel (FPSO). These floating storage systems are ship shaped and may be either purpose built or converted crude tankers. They may be used in conjunction with any type of fixed structure (such as a steel jacket or compliant tower) or floating (such as a semi-submersible) platform. They may be used in any water depths where moorings and risers can be installed. The FSO / FPSO in the deepest water to date is in the order of 2,000 m, installed offshore Brazil and Angola.

In deep water the riser design is highly specialised, becoming a critical component of the production train. It is normal for deepwater oil production to combine processing and storage capability, leading to most deepwater applications being FPSOs.

Where floating storage is used in shallower water, in conjunction with fixed platform, the storage vessel is moored a safe distance from the platform and connected to the platform by a subsea pipeline and riser. Typically a Catenary Anchor Leg Mooring (CALM) buoy is used for the mooring though variants such as Single Anchor Leg Moorings (SALMs) or turret moorings may be used. Calms are probably the preferred choice for areas requiring continuous station keeping in all weather conditions.

There are many CALM/SALM systems used throughout the world, particularly in the North Sea. The Legendre FSO off the Western Australia coast is turret moored.

If used for a Browse LNG development a FSO would likely remain permanently moored and continuously manned with a small crew except during severe cyclonic activity.

FSOs are well tried and generally should have an availability of 98% except for interruptions for cyclonic weather. Storage could be expected to be a minimum of 10 days production of 300,000 bbl whichever is the greater.

5.2.2 Concrete Gravity Structure

An alternative to using a FSO for offshore condensate storage is to use a CGS. This could be simply a concrete storage tank that sits on the sea floor or a concrete platform with integrated storage that sits on the sea floor. A platform would have processing equipment, such as gas and condensate drying equipment, condensate stabilization facilities and well control equipment on it. In contrast to a FSO a CGS is restricted in the water depth in which it can be used. The deepest CGS to date is the Troll platform in the North Sea in 303 m water. CGSs have been used in the North Sea. Two have been used in Australia for the Tuna and Wandoor platforms.

A CGS can be used when soil conditions are unsuitable for a piled steel jacket. They also have high load carrying capacity and so can support large processing equipment.

A CGS is used in conjunction with a mooring buoy to load tankers, similar to a FSO.
The choice between a CGS and a platform of some type with a FSO is an economic decision and is not affected by the distance of a hub from the field or the condensate loading facility.

5.2.3 Shared Offshore Storage and Loading Facilities

If two fields in the Browse Basin close to each other, say within 50 km, are developed there is the potential to share certain offshore facilities. Historically, such sharing is more likely if the fields are operated by the same company or held by the same joint venture parties. It is uncommon for the development of fields held by different joint ventures to be designed to share common offshore facilities.

Facilities that could be shared include condensate storage and loading facilities. A possible scenario is two or more fields in the Browse Basin, containing high levels of carbon dioxide, are developed and a platform of some type is installed for each field to dry the gas and separate condensate. If the platforms are more than about 150 km from shore the condensate would be either piped to shore in a separate pipeline or stored offshore and loaded offshore. If the two platforms are relatively close then it is possible condensate storage and loading facilities could be shared.

If condensate storage is to be shared it is likely that the stabilisation facilities would also be shared. It is much cheaper to build one large plant to stabilise condensate than to build two small plants with the same total capacity. If a concrete gravity structure was used for condensate storage then the stabilisation facilities would be located on the CGS. If a FSO was used the stabilisation facilities would be located on the FSO. The two condensate products would most likely be mixed but could also be stored as separate products.

If storage facilities were shared then loading facilities would also be shared.

It would also be possible for each development to have its own condensate storage facilities but to share loading facilities.

There should be no metering or fiscal allocation issues if loading facilities and/or storage facilities are shared by different projects. If the projects share stabilisation facilities the separate condensate streams to the stabilisation facilities would be “live” condensate, that is, containing dissolved gases. For accurate measurement the stream should be a single phase liquid stream which should not be a problem. The stream would be sampled periodically so that the condensate sold could be allocated back to the fields from whence it was sourced.

If only the storage or loading facilities were shared, the condensate streams to the facilities would be suitable for transportation, that is with a low vapour pressure. Measurement would not be a problem. Again the stream would be sampled periodically for allocation of the condensate sold back to its source.
The sharing of offshore storage or loading facilities is unlikely to be influenced by the use of a gas processing hub or the distance of a hub to the fields.

The Inpex operated Ichthys field is some 150 km from the Woodside operated Torosa, Brecknock and Calliance fields and it is unlikely that there will be any sharing of offshore facilities irrespective of whether or not there is an onshore gas processing hub or where a standalone liquefaction plant might be located.

Where offshore facilities overseas are shared by different joint ventures, this has usually occurred during the life of the facility, frequently late in its life when it is no longer being used at its full capacity.
6. FIELD LIFE ISSUES

6.1 Operational Life of Initial Offshore Facilities

LNG projects are designed to operate at capacity for in excess of twenty years. Three of the very early LNG plants in the world; Camel plant in Algeria (started production 1964), Kenai plant in Alaska (started production 1969) and the Brega plant in Libya (started production 1970) are all still operating. These plants are all onshore and are supplied from onshore gas fields.

The life of the offshore facilities installed as part of an initial Browse Basin LNG project will likely be determined by the size of the reserves available and the capacity of the liquefaction facilities. Historically a greenfields LNG project has consisted of two LNG trains. In many cases additional trains have subsequently been added to the initial two, as for example with the NWS project. In some cases additional fields have been developed to supply gas to an expanded plant.

The design life of the offshore facilities should be chosen based on the reserves of the fields that they serve with some thought given to the exploration potential in the area.

It has frequently been found possible to extend the life of facilities beyond their design life by modification or by a change in operating conditions.

6.2 Field Life Overlap Issues

The different fields to be developed for Browse Basin LNG will almost certainly have different field lives. Even within a project fields or reservoirs are likely to be developed sequentially. For example for the Ichthys field it is likely that the more liquids rich Brewster formation will be developed ahead of the Plover formation, while for the Torosa/Brecknock/Calliance fields it is likely that the more liquid rich field(s) will be developed first. It is likely that each project will be designed for sequential development and provision made for future tie-ins to the initial facilities.

Each of the fields or reservoirs will have a different field life and the producing periods will overlap. For example if, in the Woodside operated project, the Calliance field is the first to start production then the next field would normally start production when the production rate from the Calliance field starts to decline and can no longer meet the capacity of the liquefaction plant, or if the capacity of the liquefaction plant is increased.

Differences in field life and overlap of field or reservoir production periods is a normal part of large offshore projects and are not expected to produce any particular issues.

As stated previously GCA considers it unlikely that the two initial proposed projects will share any offshore facilities.
Each of the initial projects will be planned to develop certain fields, for example the Woodside operated project - the Torosa, Brecknock and Calliance fields, and the Inpex operated project - the Ichthys field. These fields are discovered and appraised and at the time of FID the joint venture will consider that sufficient is known about the fields to make an investment decision. The project proponents will be confident making a certain amount of pre-investment for activities that will take place later in the project development. It can be anticipated that for each project a large amount of investment will take place, after the initial investment, for example for drilling wells, installing subsea equipment, and installing compression. A certain amount of pre-investment will likely be made to reduce the cost of these subsequent activities.

However, if offshore processing or transportation of third party gas is not firmly contracted at the time of FID it is unlikely that significant pre-investment will be made for the possibility of it eventuating in the future.
7. MULTIPLE DEVELOPMENT PHASES

In the past, Australian LNG projects have been developed in phases, typically a train at a time, as markets are secured (North West Shelf JV) or as gas reserves are proved up (Darwin LNG). However, as the market for LNG has become “deeper”, and where the gas resources are sufficient, there is a movement to the initial development using large multiple trains to achieve economies of scale (Gorgon).

Both Inpex and Woodside are proposing to follow this path by committing to multiple train initial developments and to production profiles that substantially commit their resource base as currently defined.

Within this broad framework, issues associated with the phasing of the development of Browse Basin gas resources can be considered as follows:-

7.1 Development for Initial Plateau Production

Both Inpex and Woodside have planned initial developments with raw gas production rates in the order of 40Mm³/day or greater. For each project, the central offshore processing facility required to separate the gas and condensate and to remove water from both streams will be very large. The size of the individual facilities, combined with the distance separating the two projects, make it very unlikely that any economies of scale could be realized by combining the two facilities into one.

For each of the “foundation” projects, a pipeline of diameter 42 to 48 inches will be required to transport gas from the offshore treating facility to the onshore plant. Laying pipelines of this diameter in the prevailing water depth is approaching the limit of available technology. A single gas pipeline serving both pipelines is very unlikely.

From a technical standpoint, and with the exception of condensate evacuation, there are no potential advantages to be realized by combining any of the offshore elements of the foundation projects. Given this situation, there are no “inter project” phasing issues to address.

Evacuation of condensate from the offshore facilities offers some opportunity for synergies and therefore has potential impact on phasing. This opportunity has the form of a single FSO, or a single pipeline to shore to handle condensate production from both the foundation projects.

7.2 Development for Maintenance of Plateau Production

Within each of the two foundation projects, additional producing wells will be required as the initial wells deplete the areas of the reservoir they access. Gas compression will be required to be added to the offshore processing facility as overall reservoir pressure declines. Within each of the foundation projects, these two ongoing requirements are interdependent and the phasing of the additional wells and the installation of process compression will be subject to ongoing optimisation; beginning with the pre- FEED studies.
7.3 **Major Additional Developments**

Should ongoing exploration in the Browse Basin yield a discovery or discoveries sufficient to support a development comparable to either of the foundation projects, the offshore elements of that development could be expected to proceed independently for the same reasons as outlined for the foundation projects in paragraphs 7.1 and 7.2 above. Given the anticipated demand for LNG, it is unlikely that such a discovery could be “held over” to “back fill” the foundation project’s facilities as production from those projects came off plateau.

7.4 **Small Incremental Developments**

Existing smaller discoveries, such as Crux, will either be “held over” to backfill the foundation projects facilities or be aggregated to the point where they can provide a resource base sufficient to support a “stand alone” development.

In summary and from a technical standpoint only, there are no substantial “inter project” phasing issues that would impact the foundation projects. Within each project no abnormal intra project phasing issues are foreseen.

However there are other considerations, such as availability of materials and construction resources which, given the size of the foundation projects and the number of similarly sized competing projects, will have a significant impact on the “interproject” phasing.
8. PIPELINE CONSTRUCTION AND INSTALLATION

8.1 General

Because of the long pipelines, high gas flow rates and water depths, the major gas pipelines for Browse Basin LNG developments are likely to be a major technical challenge. In dealing with specific issues of Browse Basin potential pipelines, the major factors to be considered are those related to water depth and geotechnical conditions.

Generally large diameter pipelines (say 40" O.D.) are placed on the sea bed from a specialised lay barge. The principal cost elements are the cost of the pipe and the hire rate for the lay-barge and its operating crew. Any factor, such as weather or metocean conditions, which slows the rate of laying increases costs dramatically. Mobilisation and demobilisation are a significant part of the cost which means that shorter pipelines are disproportionately more expensive per kilometre than longer ones.

The first factor to consider is water depth. Continuous lengths of pipe are laid from the rear of the pipe lay vessel, in what is referred to as an S lay configuration, reflecting the shape of the pipe as it comes off the pipe lay vessel, bending as it descends vertically and becoming horizontal again as it is laid on the sea bed. (In specialised situations of very deepwater this may be a J lay configuration in which the pipe is laid vertically into the sea). The mechanical design of the system is such as to dictate a maximum radius for the bends in the S configuration. These radii are controlled by maintaining a tension in the pipeline, created by the lay vessel pulling with engines or anchors against the pipeline. Such operation effects the forward speed of the vessel, and hence the greater the pipeline depth the slower the lay vessel speed and the greater the duration of the operation, directly effecting the cost.

The pipe may also require a concrete weight coating to provide stability since pipelines above about 12" may be buoyant in sea water. This considerably affects the required tension, affecting the lay rates compared with a plain pipe and hence the cost of the laying operation.

There are three principle zones along the pipeline route to consider –

- near platform zone, in relatively deep water
- main length of the line from the platform towards the reception facilities which may be on land or another floating/fixed structure, and
- shore approaches

8.2 Near Platform Zone

In the near platform area pipelines are normally buried to depths of approximately 2 metres for protection against dropped objects. If anchors are a hazard, burial may be to around 5 metres. There are number of different techniques for creating the trench in order to bury a pipeline, from ploughs pulled by the lay barge to powerful water jetting systems, including excavation equipment on vessels. Each has its cost and productivity depending on the nature of the seabed.
In the platform area the nature of the termination of the pipeline connection to the platform facilities will also involve high unit costs since specialised hyperbaric welding teams and supporting vessels may be needed to make the connections.

8.3 Main Pipeline Length

Along the pipeline route it is not normally necessary to bury the pipeline if water depths are in excess of say 60 m. The pipeline is laid directly onto the sea bed, remaining stable by virtue of its concrete weight coating. However, if the sea bed area is subject to strong lateral currents, there can be a risk of pipeline mobility which must be counteracted by stabilising the pipeline. This can be carried out in a variety of ways, most commonly by burying the pipeline or by dumping rock onto the line, or by some form of captive system to pin the line to the sea bed. The choice of the preferred option is dictated by cost which is substantially affected by the nature of the sea bed, varying from exposed hard rock through to soft sand or silt. In light sand and silt, burial can be effected relatively cost effectively by a submarine plough towed by the lay barge. In other cases a trenching vessel will excavate a trench and the pipeline will be laid into it, becoming covered by sediment with time. Naturally the ease with which these collateral operations are carried out dramatically effects the overall cost since the ultimate lay rate is linked to them.

A major concern along the pipeline route will be continuity of the sea bed to provide continuous support. Often localised sea bed features can occur which could result in sections of the pipeline being unsupported and having to span over substantial distances. This can lead to weakness in the pipeline integrity and would normally be avoided by selection of an alternative, though longer route.

8.4 Shore Approaches

Below about 60 m water depth, and for onshore approaches, pipelines should be buried to depths of over 1 metre as protection principally against trawler boards from fishing activity. Close to shore the pipe cannot be laid by a lay barge due to water depth considerations and special shore approach work has to be set up to pull the pipeline into the beach. Pipeline pull machinery, coffer dams and excavated channels will be needed to carry this out. The pipeline would normally be buried right across the beach and the near land terrain, with special attention being given to restitution of the impact of the work. In special cases where the shore approach involves traversing cliffs and other hard rock features, or crosses areas of special interest, then horizontal drilling could be employed or tunnels excavated to take pipelines. As well as the impact of these activities on cost, often the mobilisation and demobilisation of special equipment to remote areas will add considerably to the implementation costs.

8.5 Processing Sites Comparison

All of these factors will be present to some extent affecting the cost of the pipelines serving the Browse basin gas fields. At this stage, without detailed survey and bathymetric data, it is not possible to identify specific construction issues for each of the potential hub sites, nor comparative differences between alternative pipeline routes serving different possible landfalls. One exception to this is the identification, in general qualitative terms, of the impact of different near shore conditions for each site location affecting the cost of the shore approaches since these ranges from sandy beaches to high cliffs.
Appendix VI shows the costs estimated by GCA for pipelines from the proposed developments operated by Woodside and Inpex to the different potential onshore processing sites. It is estimated that 40 inch diameter line will cost in the order A$4 million/km. The main effect of the location of an onshore gas processing hub on offshore developments is on the length of the pipelines from the fields to the hub.

8.6 Equipment Availability

In deep water such as in the vicinity of the Woodside and Inpex operated fields, the maximum diameter of pipelines that can be laid will be limited to about 40 inch diameter. Even then there are a very limited number of pipelay vessels that can lay pipe of this diameter in deep water. The availability of these vessels can impact on project schedule.

In shallower water, less than about 300 m, the large pipelay vessels are capable of laying pipelines up to about 48 inch diameter. There is also a larger selection of vessels for laying lines 40 inch diameter and below in shallower water. The availability of a suitable pipelay vessel is less likely to impact on project schedule in these circumstances.

If Darwin or Burrup were selected as the processing hub the availability of sufficient pipe for the offshore pipelines would be a critical schedule issue. The Browse Basin fields proposed for LNG development are 800 – 1000 km from Burrup or Darwin and obtaining large diameter high pressure pipe for this distance could impact on the project schedule.
APPENDIX I

RFT DOIR2271107 - SCOPE OF SERVICES – EXTRACT

It is envisaged that any offshore development of the Browse gas fields to evacuate the Browse Basin to a common onshore location will comprise a combination of:

- Subsea wells tied back to in-field or near-field production facilities;
- Floating production facilities located in deepwater areas;
- Fixed production facilities in shallow (~150m) water depths;
- A number of in-field flowlines, and intrafield pipelines to connect processing facilities; and
- Large diameter pipeline/s to transport gas to the onshore processing capacity.

While it is acknowledged that the decisions surrounding the configuration of the in-field facilities is a complex proposition that will be the subject of review in conjunction with the approval of the field development plan for each individual resource, it is important to understand the feasibility of the tieback of multiple fields to a common onshore gas processing hub.

The objective of this area of study is therefore to consider and evaluate the key technical issues that may potentially constrain the offshore development to support the onshore hub, including but not limited to:

- Maximum multiphase flow tieback distances, i.e. maximum distance from wellheads to the first processing facility;
- Location and configuration of condensate handling, storage and export facilities;
- Likely combinations of offshore production facilities; and
- Limitations in terms of pipeline configurations and capacities for the gas trunkline to shore.

Management of liquids recovered from the gas stream is understood to be a critical enabler to the hub development. A number of alternate strategies are available for the treatment and export of condensate recovered from the gas fields including:

- Multiphase flow of unprocessed wellstream fluids to shore;
- Offshore condensate separation and a separate condensate pipeline to shore;
- Offshore condensate removal with an offshore FSO (Floating Storage and Offloading) facility for condensate storage and export to trading tankers;
- Offshore condensate removal with storage in a CGS (Concrete Gravity Storage) with condensate export via a Catenary Anchor Leg Mooring buoy.

Given the range of potential condensate export strategies:

- Provide commentary on the relative merits of each of the above alternatives;
- Comment on likely required storage volume for offshore storage; and
- Implications in terms of metering and fiscal allocation of shared offshore storage and offloading facilities.
Given a typical offshore facility design life of 30 years, provide commentary on the following:

- Likely operational life of the offshore facilities envisaged as part of the initial development of the Browse basin;
- Comment on any potential issues surrounding the difference (if any) of the anticipated field life overlap between fields;
- Comment on any potential issues surrounding multiple phases of development around the offshore facilities and the implications this may have on the decision to progress with either fixed or floating facilities.

A number of in-field and intra-field pipelines are envisaged to transfer fluids to/from production facilities, provide discussion on:

- Maximum tieback distances, and operational issues including:
  - Wax / hydrate management strategies
  - Liquids (slug volume) management
  - Corrosion control and integrity management
- Pipeline construction and installation issues related to geotechnical, high tidal and extreme weather events;

For the export pipeline/s to shore, provide commentary on likely issues to be considered including:

- Likely sizing of the initial export pipeline/s to shore, including identification of constraints in terms of pipeline diameter / compression configuration;
- Likelihood of single phase gas pipeline/s to shore, with condensate recovery offshore as opposed to multiphase line/s to shore; and
- Operational constraints for installation of large diameter pipelines given the range of water depths anticipated from either fixed or floating production facilities.
APPENDIX II

GLOSSARY
GLOSSARY

ALSOCL Australian LNG Ship, operating Company Ltd.
bar The bar (symbol bar), decibar (symbol dbar) and the millibar (symbol mbar, also mb) are units of pressure. The bar is still widely used in descriptions of pressure because it is about the same as atmospheric pressure.
Btu The British thermal unit (BTU or Btu) is a unit of energy used in the power, steam generation, and heating and air conditioning industries. One BTU is approximately 1,054—1,060 kJ (kilojoules).
CALM Centenary Anchor Leg Mooring
CGR Condensate to Gas Ratio
CGS Concrete Gravity Structure
CRA Corrosion resistant alloy
DWT DWT, for deadweight tones, is the displacement at any loaded condition minus the lightship weight. It includes the crew, passengers, cargo, fuel, water, and stores. Like Displacement, it is often expressed in long tons or in metric tons.
EPBC Environmental Protection and Biodiversity Conservation Act
FPS Floating Production System
FPSO Floating Production, Storage and Offloading System
FPS Floating Production System
GCA Gaffney, Cline & Associates
ha A hectare (symbol ha) is a unit of area equal to 10,000 square meters, or one square hectometer, and commonly used for measuring land area. A 100 m square is one ha.
km Kilometre(s)
LNG LNG is natural gas that has been converted to liquid form for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas at a stove burner tip. It is odorless, colorless, non-corrosive, and non-toxic. The liquefaction process involves removal of certain components, such as dust, helium, water, and heavy hydrocarbons, which could cause difficulty downstream, and then condensation into a liquid at close to atmospheric pressure (Maximum Transport Pressure set around 25 kPa (3.6psi)) by cooling it to approximately −163 °C (−260 °F).
LOA Length Over All, commonly used to indicate maximum hull length of a vessel. LOA is the most commonly-used way of expressing the size of a boat.
LPG Liquefied petroleum gas (also called LPG, LP Gas, or autogas) is a mixture of hydrocarbon gases used as a fuel in heating appliances and vehicles, as well as as an aerosol propellant and a refrigerant. Varieties of LPG bought and sold include mixes that are primarily propane, mixes that are primarily butane, and the more common, mixes including both propane (60%) and butane (40%).
MEG Monoethylene glycol
Mtpa Million tones per annum
PPP Public-Private Partnership, the operation of a service in the partnership of government and the private sector.
In some types of PPP, the government uses tax revenue to provide capital for investment, with operations run jointly with the private sector or under contract (see contracting out). In other types (notably the Private Finance Initiative), capital investment is made by the private sector on the strength of a contract with government to provide agreed services. Government contributions to a PPP may also be in kind (notably the transfer of existing assets).
psi: The pound per square inch or, more accurately, pound-force per square inch (symbol: psi or lbf/in² or lbf/in²) is a unit of pressure or of stress. It is the pressure resulting from a force of one pound-force applied to an area of one square inch: 1 psi (6.894757 kPa) = Pascal (Pa) is the SI unit of pressure.

SALM: Single Anchor Leg Mooring

SPM: Single Point Mooring are loading Buoys anchored offshore, which serve as a mooring point for tankers to (off)load gas or fluid products. They are the link between the geostatic subsea manifold connections and the weathervaning tanker. The main purpose of the buoy is to transfer fluids between onshore or offshore facilities and the moored tanker.

SRTM: The Shuttle Radar Topography Mission (SRTM) obtained elevation data on a near-global scale to generate the most complete high-resolution digital topographic database of Earth. SRTM consisted of a specially modified radar system that flew onboard the Space Shuttle Endeavour during an 11-day mission in February of 2000. SRTM is an international project spearheaded by the National Geospatial-Intelligence Agency (NGA) and the National Aeronautics and Space Administration (NASA).

Tcf: Trillion cubic feet

TCS: Thompson Clarke Shipping

TEG: Triethylene glycol

TLP: Tension Leg Platform

WEL: Woodside Energy Limited
APPENDIX III

CONVERSION FACTORS
CONVERSION FACTORS

To convert Tcf to Gm3 multiply by 28.3
To convert MMbbls to GL multiply by 0.159
APPENDIX IV

DETAILS OF INTERESTS IN WOODSIDE OPERATED PROJECT
## DETAILS OF INTERESTS IN WOODSIDE OPERATED PROJECT

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APPENDIX V

DETAILS OF MAJOR MULTIPHASE OFFSHORE GAS PIPE LINES
# Details of Major Offshore Multi-Phase Gas Pipe Lines

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<td>89</td>
<td>2003</td>
</tr>
<tr>
<td>Snohvit</td>
<td>143</td>
<td>28</td>
<td>26</td>
<td>345</td>
<td>2005</td>
</tr>
<tr>
<td>South Pars 2+3</td>
<td>105</td>
<td>32</td>
<td>60</td>
<td>65</td>
<td>2002</td>
</tr>
<tr>
<td>TOGI</td>
<td>48</td>
<td>20</td>
<td>2</td>
<td>300</td>
<td>1991</td>
</tr>
<tr>
<td>Troll</td>
<td>65</td>
<td>36</td>
<td>3</td>
<td>300</td>
<td>1995</td>
</tr>
</tbody>
</table>
APPENDIX VI

GCA ESTIMATED PIPELINE AND INFRASTRUCTURE COSTS
The relative costs of co-locating the Ichthys and Browse projects at the potential sites for a single or multi operator LNG hub have been assessed. This analysis has been undertaken at a very high level, focusing on quantifying the cost differences between the candidate sites for an LNG hub. The main differentiating costs relate pipelines and compression platforms, with infrastructure and site preparation costs having less impact. The costs used for different scenarios should be considered as having an error band in the range of $+100\% / -50\%$. The results are summarised in the table below:

### GCA ESTIMATED PIPELINE AND INFRASTRUCTURE COSTS – US$ MILLION

<table>
<thead>
<tr>
<th></th>
<th>Offshore</th>
<th>Onshore</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pipelines</td>
<td>Compressor platforms</td>
</tr>
<tr>
<td>From Ichthys</td>
<td>From Browse Project</td>
<td></td>
</tr>
<tr>
<td>North Kimberley</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maret Islands</td>
<td>800</td>
<td>1,360</td>
</tr>
<tr>
<td>Bigge Island</td>
<td>860</td>
<td>1,440</td>
</tr>
<tr>
<td>Champagny Islands West</td>
<td>760</td>
<td>1,160</td>
</tr>
<tr>
<td>Wilson Point</td>
<td>880</td>
<td>1,280</td>
</tr>
<tr>
<td>Koolan Island</td>
<td>1,000</td>
<td>1,240</td>
</tr>
<tr>
<td>South Kimberley</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cape Leveque</td>
<td>1,200</td>
<td>1,160</td>
</tr>
<tr>
<td>Lombadina (Packer Island)</td>
<td>1,240</td>
<td>1,200</td>
</tr>
<tr>
<td>North Head / Perpendicular Head</td>
<td>1,480</td>
<td>1,320</td>
</tr>
<tr>
<td>Quondong Point</td>
<td>1,880</td>
<td>1,680</td>
</tr>
<tr>
<td>Fisherman’s Bend</td>
<td>2,160</td>
<td>1,920</td>
</tr>
<tr>
<td>Offshore Kimberley</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Scott Reef</td>
<td>600</td>
<td></td>
</tr>
<tr>
<td>Echuca Shoals</td>
<td>300</td>
<td>800</td>
</tr>
<tr>
<td>Existing developments</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burrup (NWS &amp; Pluto)</td>
<td>4,080</td>
<td>3,640</td>
</tr>
<tr>
<td>Darwin (Darwin LNG)</td>
<td>3,320</td>
<td>3,920</td>
</tr>
</tbody>
</table>

* Infrastructure includes jetty, breakwater, harbour, airport/helipad, roads
** Suited only to single operator LNG Hub

The Northern Kimberley sites of Bigge Island, Wilson Point and the Southern Kimberley site of Cape Leveque offer the least expensive technically acceptable overall options to accommodate a full gas processing hub.

Within the accuracy of this exercise, the other South Kimberley sites listed have broadly similar technical challenges, and offer the second least expensive option. All have the land available to expand to a full gas processing hub. However, costs increase very significantly as the distance from the fields to these sites increase:

Expansion of existing facilities or the creation of new sites at the Burrup Peninsula or Darwin for a foundation Browse development are clearly the least economic options because of the cost of the trunklines and compression required to transmit the gas an extra 600 to 800 km.